Appendix G: SOME ASPECTS OF SULFUR EMISSION TAXES IN THE PRESENCE OF ADVANCING CONTROL TECHNOLOGY FOR POWER PLANTS

G.1 Introduction

Most of the conclusions of this report are based on the assumption that the producer-emitter makes his input choices in a static environment, with certain knowledge of input costs and finite set of alternative inputs. One assumption was that only three hardware control options (dry limestone, wet limestone, and magnesia base scrubbing) would be available to the power plant, at a known cost per unit of production capacity in 1978. The purpose of this appendix is to reexamine that assumption and its effect on the results of this study in the light of other control alternatives that are expected to be available beginning in 1980.

Whereas regulations define specific reductions that must be achieved by all plants that comply with these directives, an emissions tax policy grants decisionmakers the latitude to avoid or to delay installing control devices. The use of a tax allows them to combine tax payments, to switch fuel, and to remove sulfur from flue gases to the extent that they deem economical. This additional flexibility not only induces efficiency in the reduction of sulfur emissions, resulting in equalization of marginal emissions reduction costs and minimization of total reduction costs (net of taxes) among plants, but also adds an element of uncertainty to the projected pattern of emissions reductions over time. This is a particularly important consideration in view of imminent improvements in control technology, for it implies that the plant may economize on resources in the long run by forfeiting tax payments in the near future to avoid getting tied into an inefficient, but currently available, control technology. Specifically, this analysis attempts to illustrate the motivations for and the extent of delays in control activities that could result from changes in assumptions regarding flue gas desulfurization equipment costs, operating characteristics, and availabilities.

Section G.2 reviews some of the technical aspects of expected post-1978 sulfur oxide control alternatives along with some preliminary estimates of the expected costs (per unit of capacity) of this equipment. In section G.3, some of the theoretical aspects of analyzing the producer-emitter's response to a sulfur emissions tax are discussed. That analysis sets the framework for the preliminary empirical investigation of these considerations in section G.4.

G.2 Some Expected SO_2 Control Alternatives for Power Plants, 1980-1985

Besides dry and wet limestone and magnesia base scrubbing--all projected to be available by 1978--there are several other SO_2 control options that currently appear attractive and amenable to practical application between 1980 and 1985. These options may be categorized as: (1) new flue gas cleaning technologies and (2) alternative low sulfur fuels. Another set of options, also mentioned here, are those that must be incorporated in new power plants, either as a nonconventional steam-generation system (nuclear fission) or as a markedly different method of conventional fossil fuel combustion (fluidized bed and combined cycle power system). Table G-1 at the end of this section summarized the anticipated costs, technical references, and dates of availability for the control options discussed here.

G.2.1 SO_2 Control Alternatives for Existing Power Plants

Two new control hardware options that are both representative and--among the emerging technologies--economically attractive are expected to become viable by 1980. They are the citrate and the double alkali SO_2 removal processes.

G.2.1.1 Citrate SO_2 Removal Process. The citrate process employs a scrubbing sodium citrate solution. This solution scrubs the flue gas stream by dissolving the SO_2 gas component into the solution which is then reacted with hydrogen sulfide (H_2S). The chemical reaction generates solid sulfur which becomes a marketable byproduct.

Although the expected removal efficiency of this process, 90 to 95 percent, is about the same or slightly greater than those projected for wet limestone and magnesia base scrubbers, the anticipated initial cost of the system is somewhat lower, estimated approximately at $39 per kilowatt of installed capacity. On an annualized basis, these capital costs, plus operating, maintenance, and servicing costs, are roughly projected at 1.95 mills per kilowatthour of output (assuming average machine load factors and the absence of credits for the sale of recovered sulfur).

G.2.1.2 Double Alkali SO_2 Removal Process. The double alkali system is similar to the wet limestone system in that its expected removal efficiency is only slightly higher, 90 percent compared to 85 percent, and in that it is a "throwaway" process. No marketable sulfur product is generated.

In this process a soluble alkali composed of a sodium salt (like Na_2SO_3) is used to strip SO_2 from the flue gas. This sulfur-bearing solution is then regenerated by reacting it with an insoluble alkali such as lime or limestone. The output from this reaction is a reusable alkaline scrubbing solution and a throwaway sludge, such as calcium sulfite.

The estimated cost of this process, projected to the available in 1980, is of the order of $24 per installed kilowatt. Annualized costs, including operation, maintenance, and servicing costs, are projected at 1.75 mills per kilowatthour under the previously mentioned assumption of average plant operating factors,

G.2.1.3 Gasified Coal. Current energy research indicates that the gasification of coal is both practical and attractive from the standpoint of emissions reduction. This process appears capable of generating a synthetic gas whose caloric content averages about 950 Btu's per cubic foot, compared to an average of 1,000 Btu's for natural gas. The synthetic gas would have a sulfur content of about 0.1 percent. A plant consuming 3 percent sulfur coal containing a comparable heat input would have to achieve a 99.5 percent sulfur removal efficiency to achieve the same emissions reductions that would accompany the use of this synthetic gas. Current best judgment indicates that the cost of producing gasified coal, not deemed feasible until 1985, will be about 60 cents per million Btu's.

G.2.2 SO_2 Control Options for New Power Plants

Conventional power plants have dual deficiencies: (1) all the sulfur in the fossil fuel being combusted gets volatized and, hence, becomes gas entrained, and (2) these plants reflect low thermal efficiencies (i.e., high fuel input to power output ratios). Some new power generating techniques remedy one or the other of these problems. These new power systems include a modification of conventional technology, fluidized bed combustion; a new concept in coal fired power systems, COGAS; and nuclear power plants.

G.2.2.1 Fluidized Bed Combustion Process. The fluidized bed process allows the combustion of coal in a bed which contains an active material such as a limestone dolomite sorbent. Between 90 and 95 percent of the sulfur in coal is diverted away from entrainment in the combustion off-gases as a result of chemical reactions which accompany this process. The pressurized (as opposed to atmospheric) fluidized bed combustion process appears the most economical of those options which follow this general concept.

This process is not expected to be commercially available until 1984 at the earliest. Current engineering judgment suggests that the capital cost of a plant equipped with the fluidized bed process will be in the neighborhood of $190 per kilowatt (compared to about $120 for current conventional plants) and will require about 6.30 mills per kilowatthour to operate (compared to 6.22 for a conventional coal-fired power plant).

G.2.2.2 Combined Cycle Power Systems. Combined cycle power production techniques combine the efficient use of energy with virtually emission-free power generation. Of the several such systems under development, the COGAS process is in the most advanced stages and appears capable of application by 1985. The acronym COGAS refers to this system's combination of coal to gas conversion with the advanced power cycle concept. The COGAS process generates a virtually sulfur-free gas from high sulfur and high ash content coal; the gas is very low in heat content, on the order of 60 Btu's per cubic foot. Once generated, the low-Btu, pressurized gas is fired in a combustion turbine. The residual energy in the flue gas from this combustion is then captured in a heat recovery boiler to which supplemental fuel is fired to produce superheated steam that is used to drive a steam turbine. This process promises not only 99-percent sulfur removal efficiencies but also increased thermal efficiencies (a measure of output to fuel input requirements) of as much as 55 percent. The projected investment requirements of such a system are about $127 per kilowatt of installed capacity; annualized operating costs are estimated at 5.20 mills per kilowatthour.

G.2.2.3 Nuclear Power Plants. Nuclear fission is a sulfur-emission-free alternative to fossil fuel combustion for central station power generation. The basic way in which nuclear power generation differs from conventional techniques is in the way the steam-generating heat is produced. All forms of nuclear power generation produce heat through a controlled nuclear fission process. Conventional reactors consume the fissile material and promise to create upward pressure on the price of uranium as those reserves become depleted. As opposed to that, the not yet fully developed breeder reactor actually generates more fuel than it consumes. The details of these production technologies are well beyond the scope of this report. Suffice it to say that the pressurized water reactor was chosen as the most representative of conventional reactors and that its investment requirements run about $175 per installed kilowatt; its annualized cost is on the order of 6.56 mills per kilowatthour. The breeder reactor would cost about $240 per installed kilowatt and on an annualized basis would cost about 6.46 mills per kilowatthour to operate. If fuel prices rise steeply and if the breeder reactor becomes fully operational, its fuel economy could obviously stimulate large-scale shifts toward this as the preferred power production technique.

G.2.3 Summary

Table G.1 summarizes the cost, operating, and availability characteristics of some attractive alternatives that are expected to be available for reducing sulfur emissions from power generation before the middle of the next decade. Technical references of those projections are also cited. For reference, the table also includes current estimates of costs relating to conventional oil- and coal-fired power plants.

G.3 Theoretical Aspects of Producer Responses to the Emissions Tax Over Time

Throughout this study it has been assumed that the power plant is the decisionmaking unit and that the plant's output is determined exogenously. Consequently, it is assumed that the plant's objective is to minimize costs subject to the output constraint. Allowing that constraint, this section attempts to derive a simple model of the producer's decision function in a dynamic setting. These general concepts are used in the following section in conjunction with the results of the computerized model and the data of table G.1 to perform a preliminary analysis of the implications inherent in the exclusive use of an emissions tax as the policy instrument of choice in achieving emissions reductions.

G.3.1 A Simple Model of Cost Minimization Without Emissions Control Policies

An existing power plant has been assumed in this report to require a fixed flow of fuel heat input (Btu_t) each year. That heat input is the product of the physical flow of fuel (F_{jt}), say tons, and the heat content (h_j) per physical unit, say Btu's per ton. The total fuel input from the chosen fuel in any year, measured in Btu's, can be stated as

$$Btu_t \equiv h_j F_{jt} \qquad \text{(G.1)}$$

Table G.1. Projected costs and availability of sulfur emissions control alternatives for power production, 1980-1985

Alternative	Initial capital requirements[a] ($/kilowatt)	Variable costs[a] Mills/kilo-watthour	Variable costs[a] Cents/ million Btu	Anticipated date of commercial availability	Sulfur emissions reduction percent[b]	Technical reference
Conventional power plants:						
Coal fired[c]	175	6.22		Currently	None	e
Oil fired[c]	168	6.94		Currently	None	e
Add-on technologies:						
Citrate process	39	1.95		1980	90-95	f
Double alkali process[d]	24	1.75		1980	90	f
Gasified coal	0		60	1985	99.5	g
Advanced fossil-fueled plants:						
Fluidized bed combustion	190	6.30		1983	92	h
Combined cycle (COGAS) system	127	5.20		1985	99	e
Nuclear power plants:						
Conventional reactor	175	6.56		Currently	100	i
Breeder reactor	240	6.46		1985	100	i

[a]All costs are estimated in current dollars; the estimates are for an average 500 MW plant.

[b]These are based on comparisons with uncontrolled emissions from the combustion of 3 percent sulfur coal.

[c]These costs do not include the capital and variable input requirements of either sulfur or particulate control systems; the forms are given as the costs of add-on technologies.

[d]Cost estimates do not include credits for the sale of recovered sulfur.

[e]Robson, F.L. et al. Technological and Economic Feasibility of Advanced Power Cycles and Methods of Producing Non-Polluting Fuels for Utility Power Stratas, Final Report submitted to EPA by VARL under Contract Number CPA 22-69-14, 1970.

[f]Rochelle, G.T., "A Critical Evaluation of Processes for the Removal of SO_2 from Power Plant Gas", Paper prepared for Air Pollution Control Association Meeting, June 1973.

[g]Edison Electric Institute, Fuels for the Electric Utility Industry 1971-85, Edison Electric Institute, 1972.

[h]Archer, D.H., et al. Evaluation of the Fluidized Bed Combustion Process, Final Report submitted to EPA by Westinghouse Research Laboratory, under Contract Number CPA 70-9, 1971.

[i]Hottel, H.C. and J.B. Howard, Chapter 4, "Nuclear Power", in New Energy Technology; Some Facts and Assessments, MIT Press, 1972.

where

Btu_t = annual fuel heat input in Btu's at time t ;

F_{jt} = physical flow of j^{th} fuel input at time t ;

h_j = Btu's per physical unit of the j^{th} fuel.

If the plant heat rate (required Btu's per kilowatthour output) is constant $(\overline{HR})$, one may alternatively express the required fuel input in terms of the heat rate and output:

$$Btu_t = (\overline{HR})(kWh_t) \tag{G.2}$$

where

$\overline{HR}$ = the plant heat rate (required Btu's per kilowatthour output)

kWh_t = required plant output in kilowatthours at time t.

By assuming that the decimal percent, by weight, of the j^{th} fuel that appears as volatized sulfur in the combustion off-gases is fixed at α_j, sulfur emissions (SU_{jt}) that would occur without control devices during any year can be stated as:

$$SU_{jt} = \alpha_j F_{jt} \tag{G.3}$$

where

SU_{jt} = annual sulfur emissions using the j^{th} fuel at time t ;

α_j = decimal percentage sulfur content of the j^{th} fuel, by weight.

If one assumes that the capital cost of the power plant is sunk and that all variable costs besides fuel are proportional to the size, not output, of the plant, then the volume of sulfur emissions may be regarded as determined by the cost minimizing flow volume of fuel. If, for example, the cheapest fuel is 3 percent sulfur coal and the plant requires F_t^* tons to meet its heat input requirements, then sulfur emissions are $\alpha_k F_k^*$, where k is the index identifying 3 percent sulfur coal and where that product satisfies the constraint of Eq. 6.2. The plant has no economic incentive to reduce emissions in the absence of emissions control policy.

G.3.2 Cost Minimization Over Time in the Presence of Emissions Control Policies

Either a regulation or a tax on emissions will force the producer to reconsider his emissions output decision. Assuming that there are m emission control technologies--the k^{th} one of which manifests an average decimal percentage collection efficiency of ε_k--and further assuming that only one such control device can be in place at any point in time, the producer can potentially achieve any one of k annual sulfur emission levels (E_{jkt}) for each fuel consumed where:

$$E_{jkt} = (1-\varepsilon_k)\, SU_{jt} \tag{G.4}$$

and where

ε_k = the sulfur collection efficiency of the k^{th} control technology;

E_{jkt} = annual sulfur emissions with k^{th} technology in place using the j^{th} fuel at time t.

Further assuming that the investment cost (I) of any control option is fixed and known in relation to the power plant's capacity (kW), one may state the initial pollution control capital requirement as:

$$I_k = A_k \, kW \tag{G.5}$$

where

KW = kilowatt capacity of the plant;

A_k = investment cost per kilowatt for the k^{th} control option;

I_k = initial capital requirement for k^{th} control option.

Also by assuming that the variable costs (V_{kt}) of operating the k^{th} sulfur removal system are proportional to plant output in kilowatthours per year (kWh_t), these costs can be expressed as

$$V_{kt} = B_k \, kWh_t \tag{G.6}$$

where

V_{kt} = annual variable costs associated with the k^{th} sulfur removal system;

B_k = variable costs per kilowatthour.

The annual tax bill (TAX) due from the power plant is the tax rate (θ) times the flow volume of sulfur emissions from the plant during the year.

$$TAX_{jkt} = \theta \, E_{jkt} \tag{G.7}$$

where

TAX_{jkt} = annual tax bill using the j^{th} fuel and k^{th} control technology at time t ;

θ = sulfur tax rate per ton of emitted sulfur.

In the presence of a sulfur emissions tax the cost minimizing plant will make a concurrent decision regarding the appropriate combination of fuel and emissions control devices. If, for every one of the n fuels available, the decisionmaker anticipates a cost (P_i) per Btu that will obtain over a T-year planning horizon, the alternative anticipated annual fuel bills ($FUEL_t$) for the plant will be

$$FUEL_{jt} = P_j h_j F_{jt} \quad \text{or} \quad P_j Btu_t \qquad \text{(G.8)}$$

where

$FUEL_{jt}$ = anticipated annual fuel bill using the j^{th} fuel;

P_j anticipated price per Btu of j^{th} fuel over the T-year planning horizon,

The producer will choose the combination of fuel costs and investment outlays that minimizes the discounted present value (PV) of costs over that planning horizon. One may state the discounted present value of the cost of using the J^{th} fuel and the k^{th} control technology T* periods from now, assuming a current opportunity cost of capital of r dollars per dollar $(0 < r < 1)$, as:

$$PV_{jk} = \left(\frac{1}{1+r}\right)^{T^*} I_k + \sum_{t=0}^{T} \left(\frac{1}{1+r}\right)^{t} Fuel_{jt} + \sum_{t=0}^{T^*} \left(\frac{1}{1+r}\right)^{t} \theta \; SU_{jt}$$

$$+ \sum_{t=T^*}^{T} \left(\frac{1}{1+r}\right)^{t} \left(V_{kt} + TAX_{jkt}\right) \qquad \text{(G.9)}$$

where

T^* = the number of periods from the current period when the installation of the control device is anticipated;

r = the opportunity cost of capital.

The first two terms in this expression represent the discounted present value of the pollution control capital and fuel outlays, respectively. The third term is the discounted present value of tax payments on sulfur emissions during the future period when no hardware controls are anticipated. The last term reflects the discounted present value of the variable costs of operating the control device, once installed. and of the tax payments on the emissions that would remain,

The producer will choose the minimum cost combination of fuels and control hardware subject to the constraint, Eq. G.2, that the fuel input equals that necessary to produce the required output. For a plant meeting the constraint in Eq. G.2, one may alternatively express output using Eq. G.1 as

$$kWh_t = \frac{1}{\overline{HR}} h_j F_{jt} \tag{G.10}$$

By using Eqs. G.2 through G.7, the dynamic cost minimization objective of Eq. G.9 may be written alternatively as

$$PV_{jk} = \left(\frac{1}{1+r}\right)^{T*} A_k kW + \sum_{t=0}^{T} \left(\frac{1}{1+r}\right)^t P_j h_j F_{jt} + \sum_{t=0}^{T*} \left(\frac{1}{1+r}\right)^t \theta \alpha_j F_{jt}$$

$$+ \sum_{t=T*}^{T} \left(\frac{1}{1+r}\right)^t \left(\frac{B_k h_j}{\overline{HR}} + \theta(1-\varepsilon_k)\alpha_j\right) F_{jt} \tag{G.11}$$

subject to: $h_j F_{jt} = (\overline{HR})(kWh_t)$.

Some general observations are already obvious from the model of Eq. G.11. First, deferring the investment an increasing number of years (increasing T*) will reduce the discounted present value of capital costs, the first term in Eq. G.11. However, offsetting that is the fact that the collection efficiency (ε_k) over those periods is zero, resulting in a higher tax bill, the third term in Eq. G.11. Furthermore, such a plan would probably involve the choice of a low sulfur fuel whose price (P_j) would be higher than that of a fuel that is economical when sulfur control technology is in place. This too would tend to increase the cost of deferring the control investment by increasing the size of the second term. On the other hand, the variable costs (B_j) of operating a currently available control device would be avoided entirely in the interim; i.e., the fourth term is zero for the first T* periods. Finally, other things being equal, a higher opportunity cost of capital is likely, ceteris paribus, to induce the deferment of investment in control technology, since that action would reduce the impact of pollution control investment costs, the first term in Eq. G.11.

By using the data in table G.1 the sensitivity of plant behavior to variations in some of the parameters in Eq. G.11 is analyzed in section G.4. The general theoretical framework of Eq. G.11 is used there to predict plant responses under alternative assumptions regarding annualized control costs, tax rates, collection efficiencies, and the expected number of years (T*) from 1978 that will elapse before the control process is available.

G.4 A Preliminary Empirical Investigation of Sulfur Emission-Tax-Induced Delays in the Removal of Sulfur Oxides from Stack Gases

To provide insight into the types of effects that time and new technologies may have beyond those assumed for this study, three synthetic plant models were developed. The hypothesized operating parameters of these plants are given in table 6.2. The table also reports approximate

Table G.2. Model plant parameters and projected SO_x removal costs

Parameters \ Plant size	Large, 1500 MW	Medium, 800 MW	Small, 350 MW
Annual Btu input (billion Btu's)	110,678.0	59,028.0	18,446.0
Annual kilowatthours output (million hours)	13,176.0	7,027.0	3,074.0
Annual uncontrolled emission rate (tons)	134,739.0	71,861.0	22,456.0
Annualized cost of control for processes:*			
Wet limestone	18.0	21.5	26.5
Magnesia base	17.8	20.2	25.7
Citrate	12.0	14.5	18.5
Double alkali	11.5	13.2	15.5

*Cents per million Btu.

Source: Research Triangle Institute.

annualized costs for two control processes, wet limestone and magnesia base scrubbing, that are attractive SO_x control options which were anticipated in other parts of this study. Also presented are anticipated annualized costs for two new technologies, the citrate and double alkali processes, expected to be available during the 1980's. The latter costs are extrapolations of those reported in table G.1.

The analytical technique used in this portion of the study was first to generate the costs of fuel switching only and the emissions tax payments that would occur at different tax rates for each plant size. These costs were projected using the basic computer model used throughout this study, Then the computer model was run again for each of three hypothetical plants, this time allowing the plant to institute cost minimizing combinations of either magnesia base or wet limestone scrubbing and fuel switching and tax payments.

In following the assumption in other parts of this report that the opportunity cost of capital is in the neighborhood of 12 percent, the “critical" level of annualized cost of a new technology available T* years from the present (for this analysis presumed to be 1978) was calculated as follows. The present value of the costs of fuel switching and tax payments over T* periods was computed. Similarly, the present value of the cost minimizing combination of currently available control options (assumed to be wet limestone and magnesia base), tax payments, and fuel switching was calculated. The "critical" value of the annualized costs of new technology options was then determined by division of the difference between the latter and former discounted costs by the appropriate discount factor.

These concepts can be stated briefly in algebraic notation. Where the annualized cost of presently available SO_x control options, including tax payments, is denoted as PT; that of fuel switching and tax payments as FS; the number of years until the new technology is available as T*; the opportunity cost of capital as r; and the "critical" value of the annualized cost of new technology and emissions tax payments as X, the point of indifference between choosing currently existing options and new options available T* years from the current year is defined by the following equality (the assumed planning horizon was 15 years):

$$\sum_{t=0}^{T^*} \left(\frac{1}{1+r}\right)^t FS + \sum_{t=T^*}^{15} \left(\frac{1}{1+r}\right)^t X = \sum_{t=0}^{15} \left(\frac{1}{1+r}\right)^t PT \qquad (G.12)$$

Since output from the basic computer model generated FS and PT and since r was assumed to be 0.12, the "critical" value (X) was calculated by the following equation:

$$X = \frac{\sum_{t=0}^{15} \left(\frac{1}{1+r}\right)^t PT - \sum_{t=0}^{T^*} FS \left(\frac{1}{1+r}\right)^t}{\sum_{t=T^*}^{15} \left(\frac{1}{1+r}\right)^t} \qquad (G.13)$$

The value given by Eq. G.13 represents the annualized cost of a new technology plus annual emissions tax payments above which the cost minimizing plant would choose to install immediately (1978) the present technology and below which it would choose to wait T* periods until the new technology was available. In the empirical work, the number of years the plant would have to wait for new technology was varied over three assumed values: 2, 4, and 6 years. For each of those values of T* and for each tax rate for which FS and PT were projected, Eq. G.13 was used to calculate the "critical" value.

Since the control cost portion of X, the sum of control costs and tax payments, depends upon the volume of emissions that remains after the application of the new control technology, alternative assumptions concerning the control efficiencies of new technologies were also made. The assumed efficiencies of control for projected SO_x control technologies were 90, 95, and 99 percent. The emissions rates in table 6.2 then allowed calculation of the annual cost of tax payment at each tax rate and control efficiency. This then yielded a net remainder available for annualized costs of owning, maintaining, and operating the SO_x control hardware. Using the annual Btu inputs, also reported in table G.2, finally allowed a computation indicating the maximum cost, in cents per million Btu, at which the deferment of current investment in favor of future (cheaper) control processes would be more economical than immediate installation of stack gas cleaning devices. The loci of those critical costs are reported in figures G.1, G.2, and G.3 for the large, medium, and small hypothetical plants, respectively.

An example of the meaning of the curves in figures G.1, G.2, and G.3 follows. Suppose that a new control process would be available by 1982, 4 years beyond 1978, at an approximate cost of 12 cents per million Btu for a 1,500 MW power plant. Further assume that the process could achieve 95 percent collection efficiencies. Would the plant wait 4 years to install the new process and pay the emissions tax penalities in the interim? If so, over what ranges of tax rates? The middle panels (B) of the figures answer those questions. For tax rates below about 7 cents and above approximately 19 cents per pound of emitted sulfur, the hypothetical plant would choose to follow current options; i.e., to install one of the currently available technologies immediately. Between those anticipated tax rates, it would choose to wait 4 years until the new technology is available. This method can be applied for any number of options among the subject plant sizes.

The cause of the peaking over the mid-range of taxes (B panels) in all three figures is that the ratios of PT to FS (annualized present technology and fuel switching costs, respectively) in Eq. G.13 follows that same pattern, by causing the corresponding values of X and, in turn, the critical values presented in those figures to follow the pattern displayed there.

It is interesting to compare the costs of the two new technologies presented in table G.2 against these figures. Recall that the citrate process promises control efficiencies over the range of 90 to 95 percent while the double alkali process is expected to manifest a control efficiency of about 90 percent. Both are expected to be available by 1980, within 2 years of the beginning of the planning horizon. Using the cost data of table G.2, one can determine from figure G.1 that large plants (1,500 MW) would be expected to wait until those processes were available for any tax

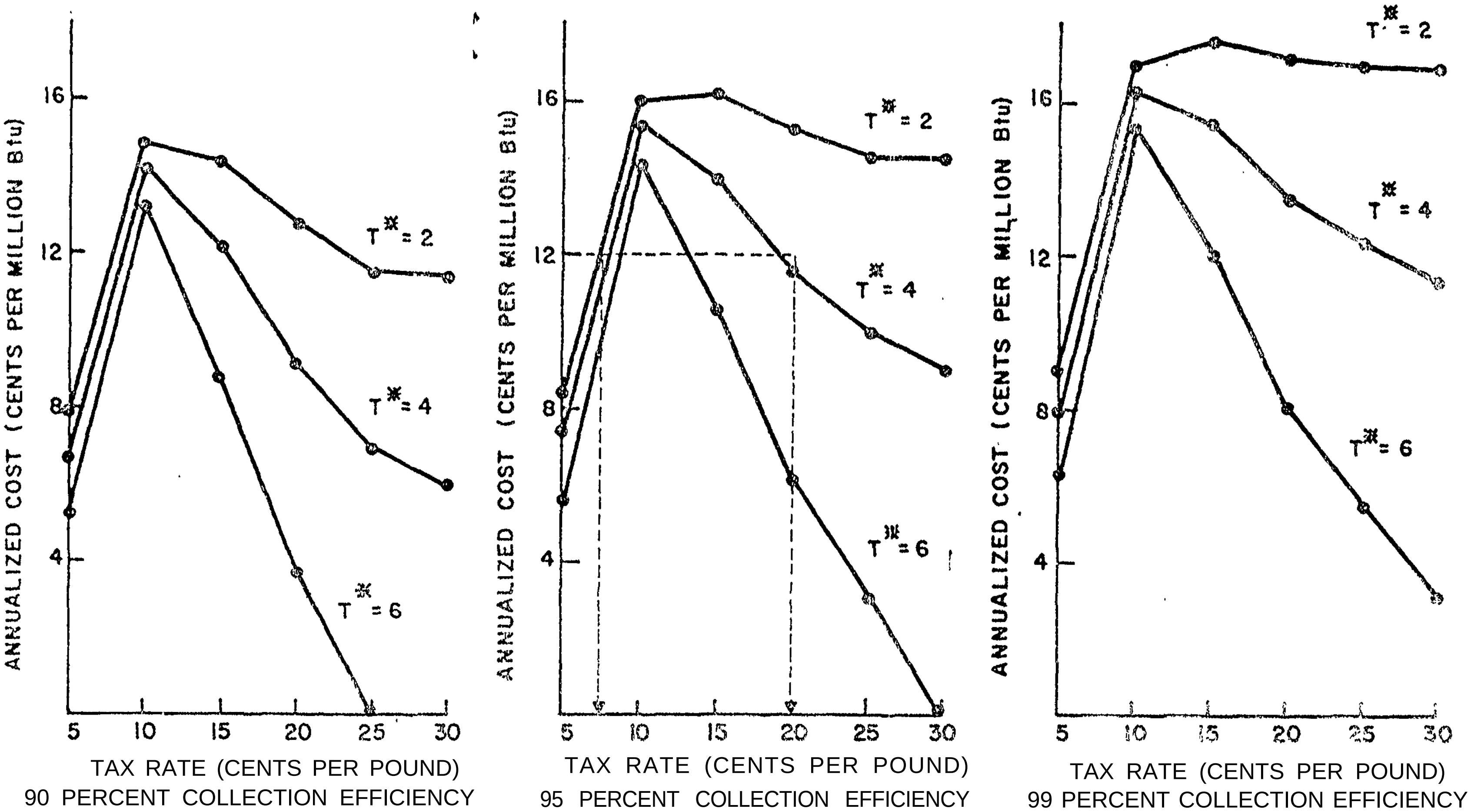

Figure G.1. Loci of anticipated costs of new SO_X control processes (available in T* years beyond 1978) below which a cost minimizing 1500 MW model power plant would defer SO_X stack gas cleaning.

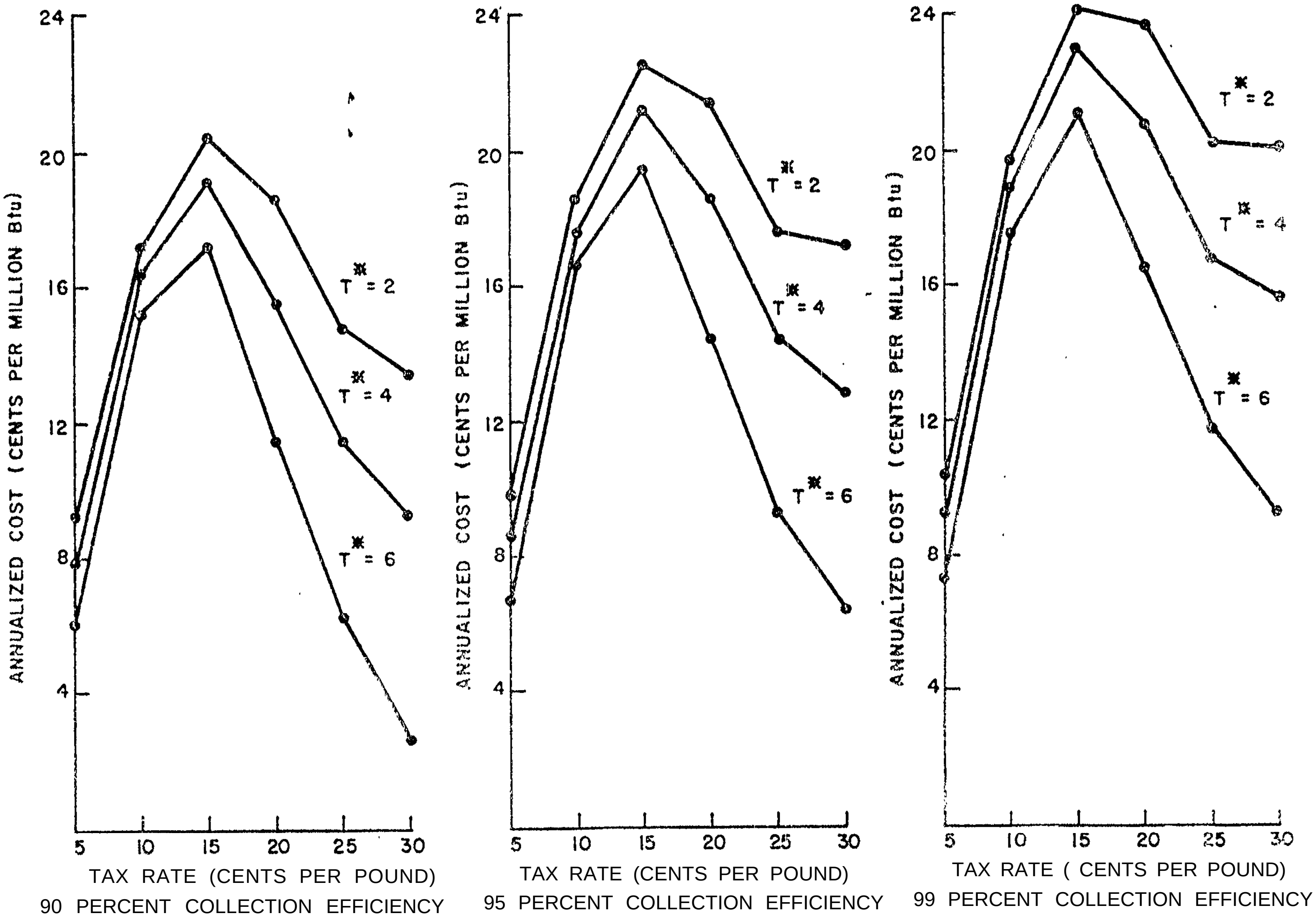

Figure G.2. Loci of anticipated costs of new SO_x control processes (available in T* years beyond 1978) below which a cost minimizing 800 MW model power plant would defer SO_x stack gas cleaning.

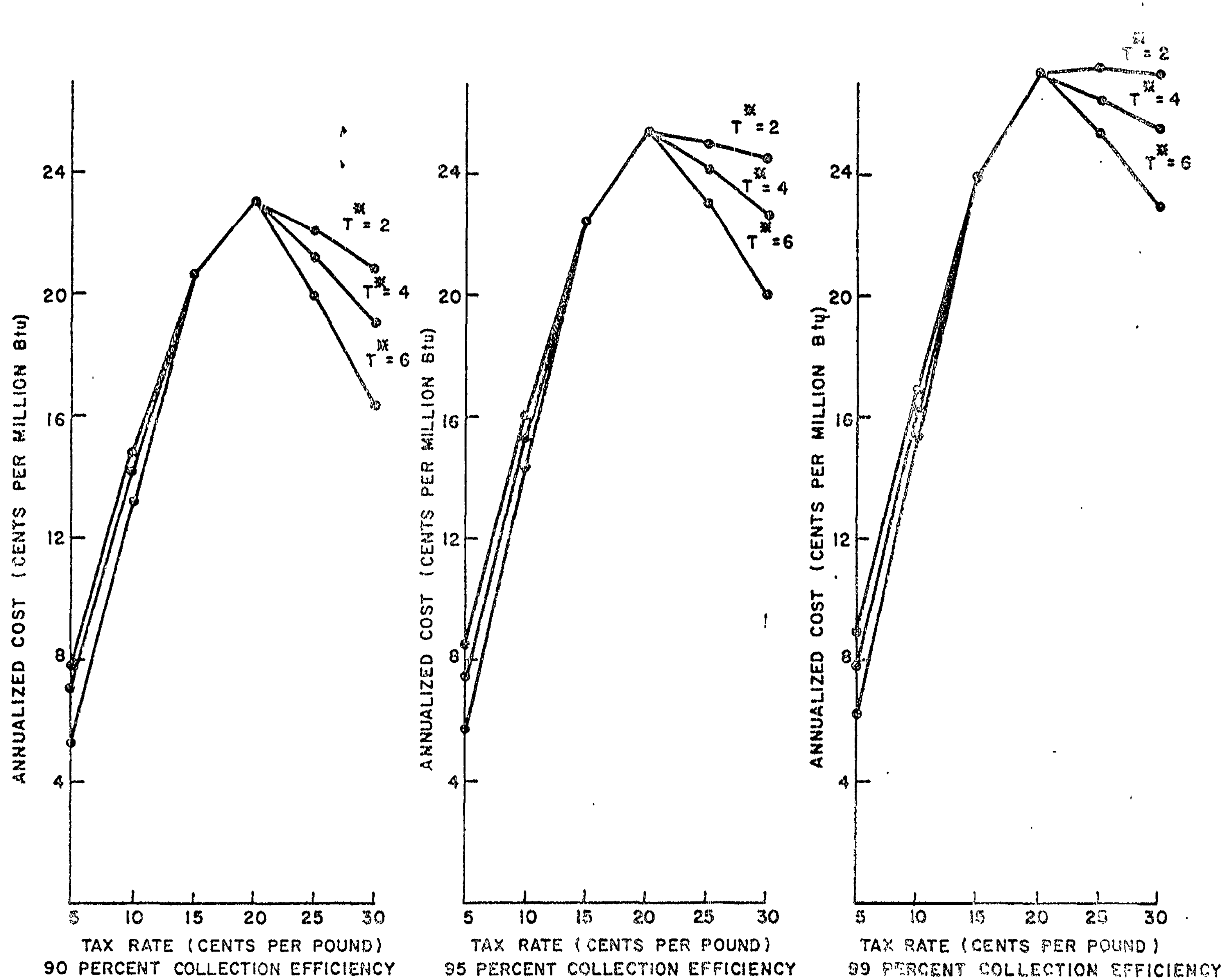

Figure G.3. Loci of anticipated costs of new SO_x control processes (available in T* years beyond 1978) below which a cost minimizing 350 MW model power plant would defer SO_x stack gas cleaning.

rates in excess of about 7 cents per pound of emitted sulfur at 90 percent efficiencies and for even lower tax rates if the control efficiency ranges up to 95 percent, Figures G.2 and G.3 indicate that virtually the same results would hold for medium- and small-sized plants. The choice of deferring or not deferring appear, for all three sizes, to be very sensitive in the range of tax rates between 5 and 10 cents, both reasonable values that have been suggested by some officials as feasible tax rates.

Quite obviously, this analysis is highly dependent on an array of assumptions about plant location, expected fuel prices, estimated costs of control options anticipated in 1978, and a multitude of other parameters. Yet it is useful in that orders of magnitude are identified and in that the directional affects of the time until new processes are available, of collection efficiencies, of tax rates, and of new source control costs are identified and, at least roughly, quantified. More complete investigations will await better refined cost models for new control options, improved knowledge of anticipated fuel costs, and intensive microanalysis of the ways in which firms, in practice, respond to uncertainty in environmental control policy parameters.